Octopus Energy's Response to the Ofgem Call for Input on Locational Pricing Assessment

Part One: The key opportunities associated with introducing more granular locational pricing in GB

To enable the development of a low cost energy system, the UK will need cost-reflective price signals. These price signals can:

- **Ensure new generation or demand takes into account all the costs and benefits** before making investment decisions, including the costs or benefits to the transmission grid, which are currently largely socialised. Over time this should reduce constraint costs by influencing where new generation or demand is located, and what it is co-located with (for instance new wind demand might in future find it more economic to co-locate with batteries or electrolyzers). It should also reduce broader system costs in the shorter term by providing pricing information to inform operational decisions, thereby encouraging more efficient use of current network infrastructure. Lastly, there are benefits outside the energy system - more cost reflective pricing could bring investment and jobs into coastal and remote communities.
- **Ensure flexibility is used where it creates the most value**. By packaging transmission-level grid constraint costs with wholesale pricing information, it is possible for flexibility providers to bring forward locational specific flexibility, capable of responding to generation surplus or deficit behind a constraint. By reflecting the true cost of a constraint, it encourages more flexibility to be provided and invested in where it is needed. Locational pricing is expected to encourage greater optimisation behind nodes thereby increasing routes to market for distributed energy resources and demand side response.
- **Help reduce the complexity of system-dispatch**. By determining a dispatchable generation stack and keeping more decision-making in the market, the complexity of system operation should be reduced. This happens because constraints are explicitly taken into account in prices, rather than the ESO being forced to take action post-gate closure to rectify a proposed, but non-dispatchable generation stack.
- **Help reduce losses by pricing these in explicitly**

Octopus Energy therefore supports the use of locational marginal pricing (LMP) as a means to improve both wholesale and transmission level cost signals, and move more decision-making to the market.

Academic literature in general confirms this view - a recent paper examined a cross-section of studies and concluded overall that "the direct benefits of nodal pricing have been estimated as between 1-4% of operational costs, which would translate into savings of several billion Euro per year in the EU. In the U.S. markets that transitioned from zonal to nodal markets, these savings exceeded the implementation costs within one year of operation."[1]

Part Two: The key implementation challenges, risks and mitigations

The short term challenge
However, we are also acutely aware that the GB system is facing shorter term decisions over the next 5 years that could add significant system costs, before the likely implementation of LMP. We are therefore keen both to move quickly on implementing LMP, learning from experiences in other jurisdictions, and to develop practical solutions to manage the period prior to LMP implementation.

Short term management of the GB system could include the identification of zones for particular asset classes (storage, renewable generation) - similar to the Australian approach, where the state governments use renewable energy zones as a planning tool to make sure new renewables can be coordinated with transmission and demand. Another approach might be the use of high-level strategic system planning to identify lower cost and no regret options to deliver the required energy system, coupled with adjustments to TNUoS, CfDs or other government subsidies. Engaging the right institution or taskforce to undertake such a review will be important, ensuring the right mix of digital and data enabled expertise, as well independence, and knowledge of the energy system.

The planning would need to consider the likely system needs (e.g. hydrogen production capacity, grid scale storage, new off-shore and on-shore wind generation, decarbonised industrial clusters) and the possible system impacts of location (primarily the impact on transmission and distribution systems). With the information about new asset requirements and system impact, an optimisation can be undertaken to identify preferred locations or zones for particular assets which significantly reduce total system costs. If there are significantly better locations for these assets, any new investments prior to the introduction of LMP would need to take location into account through reform of government support schemes.

Implementation challenges
Lastly, there are four key interrelated challenges we see with LMP which will need more attention: investment, liquidity, the impact on domestic consumers and market power. These are practical issues with LMP that have been identified elsewhere in the world, and solutions have been developed to address these. It is important that Ofgem moves to quickly identify suitable options for a GB market context. The more quickly LMP is implemented, the greater the benefits for the GB system.

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[1] **Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate,** An MIT Energy Initiative Working Paper February 2022, Anselm Eicke, Tim Schittekatte

The first challenge is the investment challenge: how to ensure that investment in renewables is maintained, both during the transition to LMP where wholesale market reform is likely to significantly increase investor uncertainty; and in the longer term, where the design of any CfD-like support mechanism will need to avoid blunting any locational signal. The generic “missing-money” problem exists in all market designs, but will still need consideration on moving to LMP to avoid impacting investment.

The second challenge is the liquidity challenge: the extreme volatility and uncertainty in wholesale markets we are experiencing currently is translating into reduced liquidity, this current trend is compounded by the shift to greater power volumes being sold in day-ahead markets, rather than through PPAs. LMP might further exacerbate these two factors driving lower liquidity. Therefore, any proposals to introduce more granular locational pricing must assess expected impacts on market liquidity, as liquidity is fundamental for continued market competition and keeping costs low for consumers. Solutions might involve the use of recognised trading hubs (a subset of nodes over which a price index is calculated as the weighted average nodal price), combined with the use of financial transmission rights (FTRs). Ofgem’s work on LMP would ideally identify proposed trading hubs, and discuss a mechanism for creating/auctioning FTRs including who the counterparty is intended to be (the FSO or market participants).

The third challenge is the consumer challenge: what might price protection look like in an LMP market, and how much price variation should consumers be exposed to (and are there any limits). By the time LMP is implemented, the price cap is likely to have evolved, but any form of price protection will need to balance the benefit of price reflectivity versus the impact on consumers. For consumers who have chosen to participate in the competitive market, consideration should be given to consumers' total price exposure, and what protections might need to be in place to avoid a Texas-like price shock.

The fourth challenge is the challenge of market power. LMP fragments the single market into 750-plus submarkets separated by possible constraints. In such a world it is possible that some market players will hold large fractions of demand or generation at a particular node, and may therefore price accordingly. For instance, a study by Professor Wolak into the NZ electricity market estimated that wholesale prices were, on average, 18 per cent higher than they would have been if the wholesale market had been more competitive, and the gentailers had not been able to exert market power[2].

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[2]https://comcom.govt.nz/news-and-media/media-releases/archive/commerce-commission-finds-that-electricity-companies-have-not-breached-the-commerce-act and https://comcom.govt.nz/__data/assets/pdf_file/0025/219094/Electricity-investigation-Investigation-report-21-May-2009.PDF

Mechanisms to address market power concerns will therefore need to be implemented, and should form part of the evaluation. For instance, the US nodal markets now routinely check and correct for over-priced bids[3] using one of two variants: use of a regulator-determined offer price (when a set of suppliers are determined to have a sufficiently large ability to exercise unilateral market power, their offer prices will be replaced with an regulator-determined offer price), and the “conduct and impact” approach (which employs a two-step process that assesses the impact of a player’s conduct on the market-clearing price, if generators offer fails the “conduct and impact” test, their offer price will be replaced by the unit’s reference level in clearing the market)

Any market design will involve trade-offs and compromises, and the challenges identified above also exist to some extent in the current GB market design. Given that LMP is working successfully in a number of markets in the US, Argentina, Chile, Mexico, New Zealand and Singapore, these challenges have for the most part been solved or significantly mitigated. We need to avoid a protracted academic discussion. Identifying appropriate solutions for the GB market using experiences from other jurisdictions, and implementing LMP quickly will create value for consumers and support the transition to net zero.

Part Three: The proposed approach to modelling zonal and nodal market designs.

We support the proposed approach to modelling a zonal market - breaking the GB system into 7 constraint zones seems pragmatic (although we note that many ESO or DSO actions might still be required to manage congestion, which would not necessarily be priced in).

The proposed nodal market design, based on transmission substations, will result in more than 750 nodes. A higher number of nodes is likely to provide a better representation of the GB transmission system, stronger price signals targeted at actual constraints, and a reduction in the socialisation of costs. However there are trade-offs: a higher number of nodes results in greater market fragmentation. This is, in turn, likely to increase the chances of market players being able to exert market power and extract monopoly rent, and makes the implementation of mechanisms to address market power essential.

[3] Market Power Mitigation Mechanisms for Wholesale Electricity Markets: Status Quo and Challenges, Christoph Graf, Emilio La Pera, Federico Quaglia, Frank A. Wolak, June 20, 2021
https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/MPM_Review_GPQW.pdf